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# Geologic storage field tests in multiple basins in Midwestern USA – lessons learned and implications for commercial deployment

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## Abstract

During the last three years, geologic storage of carbon dioxide ($CO_2$) in saline formations has been demonstrated in three distinct geologic settings by the Midwestern Regional Carbon Sequestration Partnership (MRCSP), one of the seven regional partnerships funded by the U.S. Department of Energy. MRCSP (www.mrcsp.org) covers a large region across nine Midwestern and Mid-Atlantic states, with several geologic provinces including: the Michigan and Appalachian Basins, the Cincinnati Arch Province, and the coastal sedimentary layers. Given the long history of coal production, much of the region is heavily dependent on coal-fired plants for electricity, and, therefore, subject to significant economic impact from carbon-emission constraints. The sedimentary formations or geologic structures across the region provide diverse options to mitigate the emissions through geologic storage of $CO_2$.

The validation for the storage potential comes through field assessments of injectivity and containment at three locations: one each in the Appalachian and Michigan Basins and one in the uplifted Cincinnati Arch region. All three field projects were conducted in a series of steps that contribute towards development of best practices for carbon capture and storage (CCS) validation that are applicable to the MRCSP region and elsewhere. Although specific practices are highly site dependent, the general steps include initial regional geologic assessment, site characterization through seismic surveys and drilling of test wells, permitting, outreach, development of a $CO_2$ supply system, injection and monitoring operations, and post-injection monitoring and site closure.

Collectively, the regional mapping and three field demonstrations provide significant insight into geologic storage feasibility over a range of rock types and properties. Two of the tested sites indicate injection and storage rates exceeding 1000 tonnes/day/well. Such rates suggest that commercial-scale applications should be possible with a reasonable number of wells. The regional mapping of these zones also indicates that the tested layers are likely to be continuous over a large area, and, therefore, have potential for large-scale, long-term injection operations required for the numerous $CO_2$ sources in the region.



*Keywords:* Geologic Sequestration of $CO_2$; MRCSP; Field tests; Appalachian Basin, Michigan Basin, Cincinnati Arch, Mt. Simon Sandstone

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## 1. Introduction

Midwestern Regional Carbon Sequestration Partnership (MRCSP) is one of the seven regional partnerships funded by the U.S. Department of Energy. MRCSP (www.mrcsp.org) covers a large region across nine Midwestern and Mid-Atlantic states, with several geologic provinces including: the Michigan and Appalachian Basins, the Cincinnati Arch Province, and the coastal sedimentary layers. Regional geologic characterization conducted during Phase I indicated significant carbon capture storage (CCS) potential in the MRSCP region [1]. The objective of Phase II (Validation Phase) was to test the safety and effectiveness of carbon sequestration and further understand the best approaches for geologic storage of $CO_2$ in the region via field validation tests. Geologic storage of $CO_2$ in saline formations was tested at three sites located along distinct geologic settings.

In many respects, drilling of the wells during Phase II had much in common with "wildcat" wells in the oil and gas industry in that the formations of interest had little to no previous exploration at the Phase II locations. Phase II characterization efforts consisted of various data collection methods, including 2-D seismic, cross-well seismic, vertical seismic profiling geophysical well logs, and core sample collection/analyses. Hydraulic analyses were conducted to evaluate reservoir properties, such as fracture pressure and permeability. Data from these tests and others helped to describe local variations, which could then be extrapolated to better understand regional characteristics. The lessons learned from these validation tests and the implications for commercial deployment are presented below.

## 2. Regional characterization/capacity estimates

Regional characterization and developing capacity estimates are particularly important for the MRCSP region; given the long history of coal production, much of the region is heavily dependent on coal-fired plants for electricity, and, therefore, subject to significant economic impact from carbon-emission constraints. As noted by Dooley [2], CCS may be more easily deployed and at lower costs in regions where large $CO_2$ emitting sources, such as power plants and industrial facilities, are in relatively close proximity to candidate sinks, given the relatively shorter transport distances that may be required. The sedimentary formations across the MRCSP region provide diverse options to mitigate the emissions through geologic storage of $CO_2$. A large team of state geological surveys and universities across the region is participating in the MRCSP's regional mapping efforts for storage targets and containment zones.

The information gathered through regional characterization efforts conducted during Phase I was valuable for planning Phase II sequestration operations. Geological maps from MRCSP's Phase I report [1] and the availability of a host site and sources of $CO_2$ were considered in selecting the potential sites and in the preliminary site evaluation to gauge the general suitability of the site for $CO_2$ storage and significance of the formations being tested. Because the injection volumes were expected to be fairly low for these small scale tests (1,000 to 10,000 tonnes $CO_2$, initially), most sites had formations with adequate capacity for testing.

## 3. Site screening and selection

Phase II comprised the collection and analysis of local site-specific data for candidate deep geologic $CO_2$ storage formations. The site screening included a general review of site logistics, environmental factors, major risk factors, geologic framework, $CO_2$ storage reservoirs, and containment layers. National Environmental Policy Act (NEPA) environmental questionnaires and a general screening to identify local sensitive environmental features (wetlands, floodplains, historical areas, etc.) were completed for each site.

Co-locating the site with an active power plant or in close proximity to a large $CO_{2e}$ emitting source also was considered very important for future commercial applicability (Figure 1). The Appalachian Basin and Cincinnati Arch test sites were both hosted by large utility companies at one of their electricity generating stations. The Michigan Basin test site was located near an enhanced oil recovery field (State-Charlton 30/31) and its $CO_2$ transmission line with $CO_2$ from natural gas processing. Each host site provided property access for the field work, site logistics, community relations, and other support to aid in completing the project.

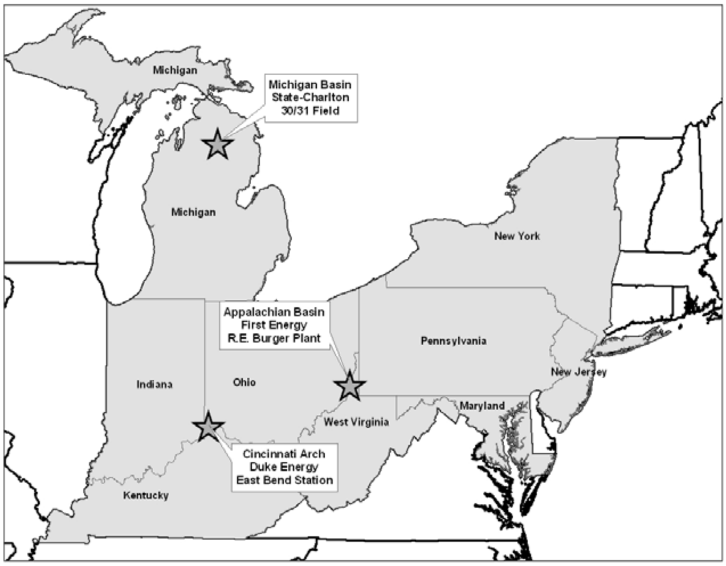


Figure 1. Site location map for the three validation phase geologic storage tests

## 4. Site characterization

The region covered by the MRCSP contains a large range of geologic features and very little previous characterization has been done within the deep saline formations of primary interest for sequestration. A more detailed analysis of nearby well logs, seismic data, borehole data, and hydraulic tests provided a better idea of $CO_2$ injectivity of rock formations.

Comparison of well data across a large geographic area offered insight into the overall nature of the rock units. At the Michigan Basin and Cincinnati Arch sites, regional well data were fairly representative of the site conditions; however, at the Appalachian Basin site, lack of regional well coverage introduced significant uncertainty in the preliminary geologic assessment. For example, the nearest similarly deep well to the Cincinnati Arch site was two miles (3 km) away. Six deep wells were present within one mile (2 km) of the Michigan Basin test well. However, the nearest similarly deep well to the Appalachian Basin site was approximately 15 miles (24 km) away.

Seismic data provided a baseline assessment of formation continuity and depth, while borehole data, including mudlogs, wireline/geophysical logging, and core data analysis provided data on permeability, porosity, density, mineralogy, and other characteristics. (While not always practical due to budget concerns, collecting whole core samples was very valuable for interpreting wireline data, particularly in carbonates.) A summary of the geologic formations of interest and approximately total volume injected for each site is provided in Table 1.

Table 1 Summary of the Geologic and Injected Volume Information for the MRCSP test sites.

| **Site Location** | **Geologic Province** | **$CO_2$ Storage Formation(s)** | | **Primary Caprock** | | **Total $CO_2$ (tonnes)** |
|---|---|---|---|---|---|---|
| | | **Identification** | **Depth (m)** | **Identification** | **Depth (m)** | |
| State Charlton 30/31 Field | Michigan Basin | Bass Islands | 1049 -1071 | Amherstburg-Lucas Formations | 682 – 893 | 60,000 |
| R.E. Burger Power Plant | Appalachian Basin | Oriskany, Salina, Clinton | 1798 - 2530 | Devonian shales | 564 - 1768 | Minimal |
| East Bend Station | Cincinnati Arch | Mount Simon | 975 -1067 | Eau Claire Formation | 848 – 985 | 1,000 |

At the Michigan Basin site, the original target sequestration interval was anticipated to include the Sylvania Sandstone, the Bois Blanc Formation, and Bass Islands Dolomite Formation. Eventual test well drilling showed that the Sylvania Sandstone was not present at the site, although, the Bass Islands Formation had suitable porosity and permeability. The overlying Bois Blanc Formation did not have low enough porosity to be considered a seal; therefore, rocks in the overlying Amherstburg-Lucas Formations were considered the immediate overlying confining interval. As there will always be uncertainties in geologic systems, the defining of the Bois Blanc as an intermediate buffer zone was important.

At the Appalachian Basin site, the test well provided specific geologic information on the Oriskany Sandstone, the Salina Formation, and the Clinton Sandstone, which are located at depths between 1798 and 2530 m. In the middle of the Salina formation, a carbonate sequence with shows of permeability and porosity and gas shows indicating moderate porosity and permeability was identified as a potential injection zone, although the later injection testing did not demonstrate sufficient injectivity, illustrating challenges for site assessment in deep basins.

The $CO_2$ storage reservoir at the Cincinnati Arch Site was the Mt. Simon Sandstone, which is an extensive sandstone rock unit that has been historically used for injection of industrial and hazardous liquid waste in the MRCSP region. The Mt. Simon Sandstone was present approximately 975 to 1067 m and had porosity primarily between 5 and 15% (based on the wireline logs). The Eau Claire Shale served as the confining layer.

## 5. Permitting

The Class V Underground Injection Control (UIC) permit option for experimental CO2 wells was used for all three sites with EPA regions 4 and 5 and Ohio EPA. Overall regulators were very interested in learning about the technology, but still applied relatively strict Class I well protocols to these small-scale tests, while allowing some flexibility to meet experimental objectives of the project. One lesson learned is that it helps to engage the UIC permitting agency early in the process. This not only makes the agency aware of the project, but it also helps in obtaining the proper forms, procedures, and regulations. From submitting the application to obtaining the permit, it may take anywhere from 6 to more than 12 months to complete the initial EPA UIC permit. In comparison, acquiring a drilling permit for an oil and gas well may take 2 to 4 weeks, with much less preparation.

## 6. Injection Operations

Injection operations followed a basic sequence of step-rate injection, period of constant injection, and pressure falloff monitoring. $CO_2$ injection rates, injection pressures, bottomhole reservoir pressures, and bottomhole temperature were measured throughout the tests. The data from the injection tests were analyzed to determine key reservoir properties, including transmissivity and permeability. The pressure falloff curves provided a better idea of overall reservoir behavior than step rate and injection tests, which could be irregular due to inconsistent injection rates, $CO_2$ phase behavior, and other factors.

About 10,000 tonnes of $CO_2$ was injected at the Michigan Basin site in early 2008. Based on the success of this phase, an additional 50,000 tonnes was injected in 2009. Injection rates ranged between 400 – 600 tonnes/day. Injection rates were limited by the $CO_2$ supply rather than the injectivity of the reservoir: analysis of the data indicated that injection rates greater than 1000 tonnes/day may be possible. During the initial test, reservoir pressures were fairly stable. However, during the extended injection period, injection test data indicated residual pressure buildup in the reservoir. The injection well showed a trend of 2.15 psi/day pressure increase and maximum bottomhole pressures were at 2086 psi, indicating possibility of finite reservoir boundary. The monitoring well located about 150 m from the injection well showed a trend of 1.66 psi/day pressure increase, and maximum pressure of 1628 psi. Post-injection pressure falloff curves compiled from the different injection tests are shown in Figure 2.

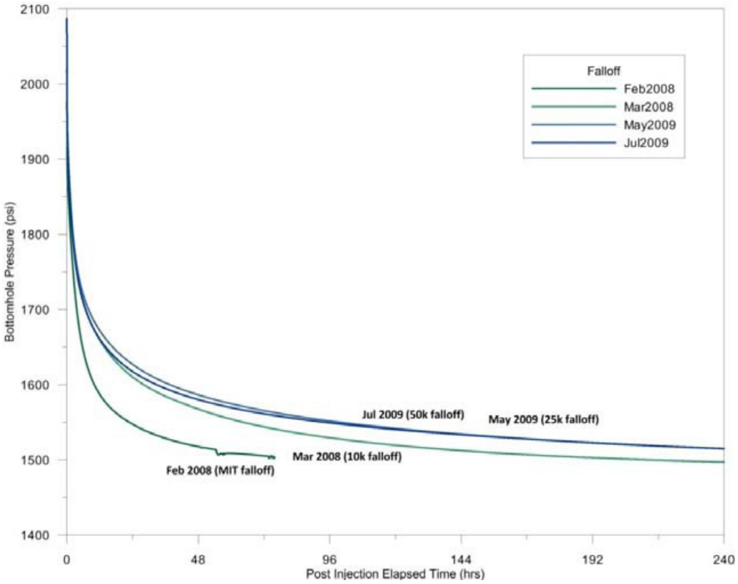


Figure 2. Michigan Basin site injection well pressure falloff curves

At the Cincinnati Arch site, approximately 900 tonnes of truck-supplied liquid $CO_2$ was injected into the well during a one week period in September 2009. Figure 3 shows the injection and pressure fall-off record from the first injection event. A $CO_2$ injection rate on the order of 5 barrels per minute (approximately equivalent to 1200 tonnes/day) was achieved during the injection test. This rate was limited by the pumping equipment used in the test, not the injectivity of the formation. At the maximum injection rate, observed bottom-hole pressure did not exceed 1900 psi. Conducting a brine injection test prior to injecting $CO_2$ was found to be a useful indicator of the ability of the formation to accept $CO_2$. At this site, injecting $CO_2$ resulted in much lower bottom-hole pressures than injecting a similar amount of brine – which suggests that brine injection tests provide a conservative estimate of $CO_2$ injectivity. Reservoir modeling is being performed to evaluate the potential maximum injectivity of the formation.

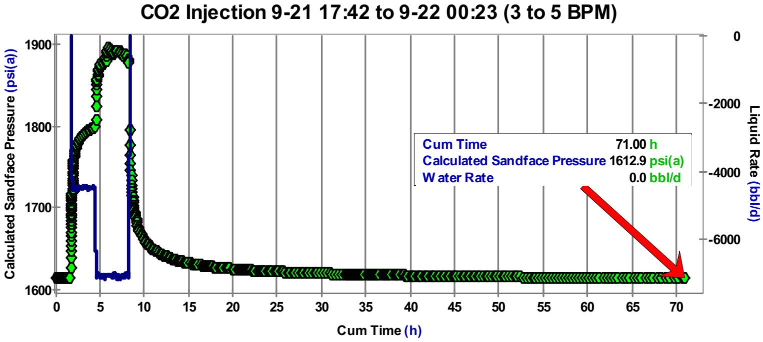


Figure 3. $CO_2$ injection and pressure fall-off record at Cincinnati Arch site

At the Appalachian Basin site, the step rate tests and periods of constant injection were limited in duration as each test formation exhibited low injectivity, despite aggressive acid treatment in the well. This site highlighted the value of smaller, research-oriented tests, which do not involve large capital investment compared to full-scale application. Initial hydraulic analysis predicted injection rates approaching 50 tonnes/day for the Salina at pressures less than 2000 psi wherein injection rates of less than 20 tonnes/day were not sustainable at twice that pressure. It is not clear whether the actual injectivity was low in these layers or whether there was some loss of injectivity due to skin effects in the borehole during 18 months period when borehole was open.

## 7. Injection Monitoring

Monitoring technologies for the injection operations [3] were chosen one of two ways. First, monitoring techniques that met the UIC permit requirements, such as pressure and temperature monitoring, were implemented. Secondly, techniques were chosen based on the size and scope of the demonstration. For instance, the Michigan Basin site is in an area with readily available pure $CO_2$ from gas processing plants, some of which is being used for enhanced oil recovery. The availability of $CO_2$ source, supporting infrastructure, and availability of nearby wells allowed larger scale injection testing and more extensive monitoring.

In addition to routine monitoring (e.g., volumetric flow (injection) rate, pressure, and temperature), innovative technologies were used to analyze $CO_2$ distribution within the subsurface. Pulsed neutron capture (PNC) tools, for example, were used to track fluid changes near the wellbore. Comparison of baseline logs taken prior to injection and logs taken after injection may make it possible to highlight zones where $CO_2$ is present, assuming the rock matrix has remained the same (Figure 4). However, PNC tools are unable to distinguish between $CO_2$ and methane as both have exceedingly low sigma values. Therefore, careful characterization of the hydrocarbon content in the formations prior to injection is necessary to help simplify results after injection. The Michigan Basin site utilized nearby monitoring wells to perform crosswell seismic surveys; through repeat surveys, it was possible to see emerging trends in the potential $CO_2$ plume as it expanded away from the injection well. Also referred to as acoustic emissions, microseismic monitoring was completed at the Michigan Basin site. Overall, microseismic arrays seem to be more practical at this site for verifying seal integrity than for plume tracking injection rates were deemed not high enough to cause significant stress to the formation to make plume tracking possible. Table 2 summarizes the monitoring tools employed at each of the three Phase II sites.

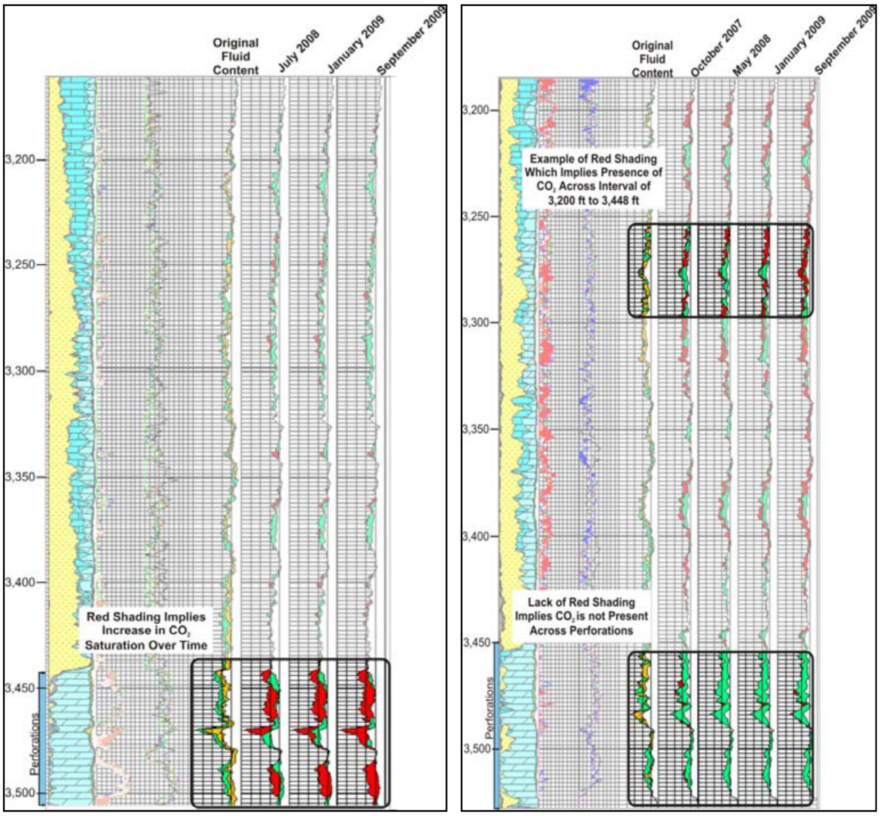


Figure 4. Time-lapsed PNC logging at the Michigan Basin Site indicates (left) $CO_2$ across the perforations within injection well and (right) within the Bois Blanc (intermediate zone) at the monitoring well.

Table 2 List of Monitoring Methods Used at Each Phase II MRCSP Site (* implies baseline only)

| Monitoring Method | Michigan Basin | Cincinnati Arch | Appalachian Basin |
|---|---|---|---|
| Injection Flow Meter | X | X | X |
| Surface Pressure/Temperature Gauges | X | X | X |
| Downhole Pressure/Temperature Gauges | X | X | X |
| Wireline Logging | X | X* | X* |
| Reservoir Brine Sampling | X | X* | X* |
| Atmospheric $CO_2$ Monitoring for Safety | X | X | X |
| Crosswell Seismic Survey | X | | |
| Microseismic (Passive) Survey | X | | |
| Perfluorcarbon (PFT) Tracer Study | X | | |
| Vertical Seismic Profile (VSP) | | X* | |
| Shallow Groundwater Sampling | | X | |

## 8. Reservoir simulations

Reservoir simulations provided information for the injection permit, system design, monitoring, and injection operations. Advanced numerical simulations were completed with the Subsurface Transport Over Multiple Phases - Water, $CO_2$, Salt, Energy (STOMP-WCSE) computer model. The model simulates parameters such as reservoir pressure, $CO_2$ saturation, $CO_2$ dissolution, and geochemical changes. The STOMP-WCSE numerical model was used to simulate supercritical $CO_2$ injection at the MRCSP Michigan Basin and Cincinnati Arch sites, and analytical equations were used for the Appalachian Basin site. Although the models provided an adequate simulation of the $CO_2$ storage process, additional adjustment to conceptual models is needed fully represent the geologic features.

For the Michigan Basin site, hydraulic test data were very useful in calibrating permeability data because permeabilities from rock core analysis were somewhat low and the model was very sensitive to permeability. For example, the core analysis of the Bass Island Dolomite indicated an average permeability of about 22 mD, however, the reservoir analysis of injection data and model calibration indicated that the actual permeability of the reservoir may be closer to 50 mD. Further adjustments to the model may include using dual porosity models to fully represent complex flow behavior in the carbonate rocks of Bois Blanc Formation.

The test data generated at the Cincinnati Arch site is being applied towards the development of a calibrated reservoir model for making scale-up predictions of $CO_2$ sequestration in the Mt. Simon Formation. $CO_2$ relative permeability data from a core sample from the Mt. Simon Formation suggests that $CO_2$ behavior may not be fully characterized by current relative permeability models. Modeling the $CO_2$ injection test proved to be difficult using existing porosity distribution functions and could only be done successfully assuming a relative permeability value of one, which is to say that $CO_2$ permeability is equal to intrinsic permeability regardless of saturation (Figure 5).

## 9. Outreach

Each site was located in a different state, with differing political cultures and specific regulatory requirements. Each site was regulated by a different agency, each of which had differing requirements for public involvement related to permitting. This highlighted a need for a tailored and systematic approach for identifying and interacting with stakeholders. For example, at all sites, "Open House" meetings were conducted in the local communities to inform and discuss issues of concern with local residents. Two meetings were held at the Cincinnati Arch site – one shortly after the site selection was announced and a later meeting as the injection was underway. Open House meetings at the Michigan Basin and Appalachian Basin sites were held in conjunction with the permit application. In Michigan, where the site was permitted as a Class V UIC site by EPA Region 5, there were no requests for a formal public meeting; however, EPA regulators attended and provided information at the meeting conducted by Battelle. At the Appalachian Basin site, which was regulated by Ohio EPA, the regulators held a formal public meeting and Battelle conducted a prior informal Open House. The regulators and Battelle staff attended and spoke at both meetings. All informational materials and activities were posted on the MRCSP Web site to facilitate information sharing among test sites and with regional partners and stakeholders. In addition, the MRCSP collaborated with other Regional Partnerships to develop a best practices manual for public outreach and education for carbon storage projects [4].

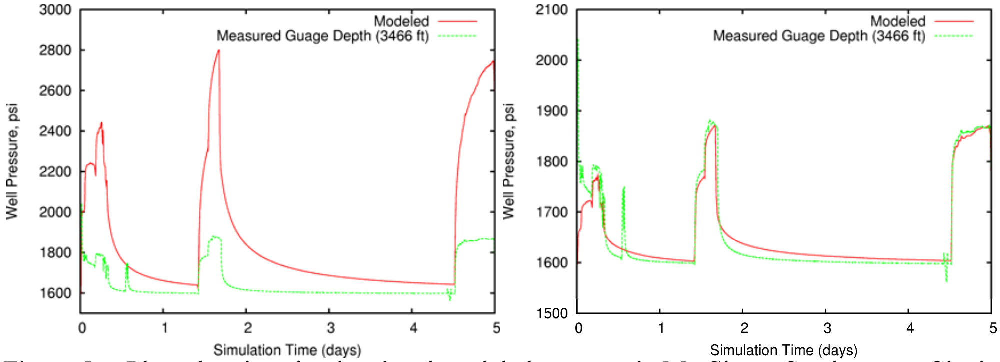


Figure 5. Plots showing simulated and modeled pressure in Mt. Simon Sandstone at Cincinnati Arch site using core derived $CO_2$ relatively permeability relationships (left) and relative permeability equal to intrinsic permeability.

## 10. Conclusions

Collectively the regional mapping and the three field demonstrations provide significant insight into geologic storage feasibility over a range of rock types and properties. Two of the tested sites (i.e., Michigan Basin and Cincinnati Arch) indicated injection and storage at rates exceeding 1000 tonnes/day/well necessary to support commercial-scale applications should be possible. The regional mapping of these zones also indicates that the tested layers are likely to be continuous over a large area and therefore have potential for large-scale, long-term injection operations for $CO_2$ sources in the region. The testing at the deeper Appalachian Basin site indicated the need for more detailed regional mapping, seismic surveys, and larger number of exploration wells before adequate storage zones with high probability of successful performance can be delineated. Overall, the tests show that the exploration and deployment strategies for CCS infrastructure in the region will be different based on the geologic setting. Furthermore, information on the stakeholder interactions also highlights the need for development of site-specific outreach efforts for differing stakeholder perspectives across the region. All these lessons are being used in development of a larger-scale storage test with injection of one million tonnes over four years starting in 2011.

## 11. References

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